BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

- -x

IN THE MATTER OF: : Docket Numbers

ELECTRICITY MARKET DESIGN AND STRUCTURE : RM01-12-000

(RTO COST BENEFIT ANALYSIS REPORT) : RT01-2-000

: RT01-10-000

: RT01-15-000

: ER02-323-000

: RT01-34-000

: RT01-35-000

: RT01-67-000

: RT01-74-000

: RT01-75-000

: RT01-77-000

: RT01-85-000

: RT01-86-000

: RT01-87-000

: RT01-88-000

: RT01-94-000

: RT01-95-000

: RT01-98-000

: RT01-99-000

: RT01-100-000

1 -- continued --

: RT01-101-000

: EC01-146-000

: ER01-3000-000

: RT02-1-000

: EL02-9-000

: EC01-156-000

: ER01-3154-000

: EL01-80-000

- -x

WESTERN REGION

REGIONAL TELECONFERENCE

FOR INDUSTRY AND PUBLIC

Hearing Room 11H-7

Federal Energy Regulatory

Commission

888 First Street, NE

Washington, D.C.

Tuesday, March 19, 2002

The above-entitled matter came on for teleconference, pursuant to notice, at 2:00 p.m.

1

P R O C E E D I N G S

(2:00 p.m.)

MR. RUSSO: Good morning everybody. My name is Tom Russo. I am with the Federal Energy Regulatory Commission and I will be hosting this afternoon's teleconference.

I want to welcome all of the 29 participants that we have on board and hope we will have a good session this afternoon.

Just a couple of things before we begin. We are not planning a presentation of any sort. The meeting is specifically for you to ask your questions and to ask us anything you want that clarifies the report's findings for you. You can also ask us to consider additional information that you would like to see.

I would just make note of the fact that your comments are due to the FERC on April 9th, and reply comments are due April 23rd.

This meeting, like all the other previous teleconferences that we've held, and we've had seven previous teleconferences, will be transcribed. I would ask each and every one of you to please state your name before you do speak.

We will be placing the transcripts in the

Standard Market Design rulemaking docket, as well as all of the relative RTO dockets. So the Commission will be using the transcripts on the teleconferences in its RTO and Standard Market Design rulemaking decisions in the future.

You can obtain a copy of the transcript in one of two ways. You can go directly to Ace and they will provide you with transcripts for a fee. Or you can wait until about ten days after we receive our copies, which is usually a day after the meetings are held, and we will place these on our web site. And those will be free of charge.

This is the last teleconference that we're having. We are scheduling a meeting here in Washington, D.C., at the Commission on March 25th beginning at 10:00 o'clock. A number of you may want to participate in that meeting either in person or by going through Capital--I can't remember the name of the company, but I will find it during the meeting.

VOICE: Connection.

MR. RUSSO: Thank you, very much.

Okay, that sort of wraps up the beginning. Now what I would like to do is introduce--have the people who are here from FERC introduce themselves. And then what I'll do is to go by the alphabet and ask each and every one of you to identify yourself by the organization that you're representing.

So let me begin with:

MR. LONGENECKER: Bill Longenecker, Office of Markets, Tariffs and Rates.

MR. FIRST: Jonathan First with FERC OGC.

MR. RUSSO: And I believe we should have Mr. Jim Turner from ICF Consulting on the line.

MR. TURNURE: Yes. This is Jim Turnure at ICF Consulting. I was the Project Manager for the Economic Assessment.

MR. RUSSO: Okay, very good. That's all we have here from the FERC and ICF Consulting, so let's begin. I would ask you--never mind. Let's begin with organizations beginning with A. Do we have any?

MR. SCOFIELD: --New Energy, Customized Energy Solutions for AEF New Energy.

MR. RUSSO: Was that ADF Energy?

MR. SCOFIELD: AEF.

THE REPORTER: And his name, please?

MR. SCOFIELD: And your name again, please?

MR. SOTO: William Scofield.

MR. RUSSO: Thank you, William. Any other A's?

(No response.)

MR. RUSSO: Let's go to B.

MR. GUY: Baltimore Gas & Electric Company, Gary Guy.

MR. RUSSO: Welcome, Gary.

MR. GUY: Thank you.

MR. RUSSO: Any other B's?

(No response.)

MR. RUSSO: Let's go to C.

(No response.)

MR. RUSSO: Are there any C's?

(No response.)

MR. RUSSO: Let's go to D.

MR. HUNTOON: Dynegy, Steve Huntoon.

THE REPORTER: I'm sorry? Steve?

MR. RUSSO: Steve Huntoon?

MR. HUNTOON: Yes.

MR. RUSSO: Can you spell that, Steve?

MR. HUNTOON: S-T-- no, just kidding. H-U-N-T-O-O-N.

MR. RUSSO: Thank you, Steve. Any other D's?

(No response.)

MR. RUSSO: Let's go to E.

MS. PERIGO: Erin Perigo, Electric Power Supply Association.

MR. RUSSO: Thank you.

MS. WICKS: Tonya Wicks with EEI Alliance of Energy Suppliers.

MR. RUSSO: Welcome.

MS. WICKS: Thank you.

MR. RUSSO: Any other E's?

MR. GREENLEE: Yes. Energy Business Watch, Steven Greenlee.

MR. RUSSO: Anybody else? Steven Greenleigh, could you spell your last name, please?

MR. GREENLEE: Sure. G-R-E-E-N-L-E-E.

MR. RUSSO: Thank you. Does that take care of the E's? Let's go to F.

(No response.)

MR. RUSSO: Any F's?

(No response.)

MR. RUSSO: G?

(No response.)

MR. RUSSO: Any G's? H?

(No response.)

MR. RUSSO: I?

MR. MARCUS: IBEW, Dave Marcus, representing a whole series of IBEW locals.

MR. RUSSO: Hi, Dave.

MR. WOLVERTON: This is Link Wolverton, Industrial Customers of Northwest Utilities.

MR. RUSSO: Welcome. Any other I's? J?

(No response.)

MR. RUSSO: K? L? M?

MR. ROARK: Merent, Jeff Roark.

MR. RUSSO: Could you tell us the name of your organization, Jeff? We didn't get that.

MR. ROARK: Merent.

MR. RUSSO: Thank you. Any other M's? N?

MR. CUTTING: John Cutting, New York Independent System Operators.

MR. RUSSO: Hi, John. Any other N's? O?

MR. LOGAN: Office of Ratepayer Advocates. This is Scott Logan, and that is with the California Commission.

MR. RUSSO: Thank you.

THE REPORTER: Could he spell his last name?

MR. RUSSO: Jeff, can you spell your last name, please?

MR. LOGAN: L-O-G-A-N.

MR. RUSSO: Thank you. P?

MR. O'MERA: Kevin O'Mera, Public Power Council.

MS. JENSEN: Betty Jensen, Public Service Electric & Gas Company.

MR. RUSSO: Could you repeat that, please?

MS. JENSEN: Betty Jensen at Public Service Electric & Gas Company.

MR. RUSSO: Betty Jensen? Is that correct?

MS. JENSEN: That's correct.

MR. RUSSO: Okay.

MR. MAGNUSON: This is Dave Magnuson with PSE.

MR. RUSSO: Okay. Any other P's?

MR. DAVIS: Alan Davis, A-L-A-N Davis, PPL Montana.

MR. RUSSO: Welcome. Other P's?

(No response.)

MR. RUSSO: Q? R?

MS. UHLER: Riverside Public Utilities, Lee Ann Uhler.

MR. RUSSO: Welcome. Can you spell your last name, Lee Ann.

MS. UHLER: Uhler, U-H-L-E-R.

MR. RUSSO: Thank you.

MS. SIMPSON: Reliant Energy, Denise Simpson.

MR. RUSSO: Welcome. Any other R's?

(No response.)

MR. RUSSO: S?

MR. HOFFMAN: Soul River Project, Biff Hoffman and Laura Whistler.

MR. RUSSO: Thank you.

MS. BROWN: Southern California Public Power Authority, Ellis Brown.

MR. RUSSO: I think we had another S?

MR. HARTING: Yes. It's Seattle City Light, and it is Jim Harding.

MR. RUSSO: Hi, Jim.

MR. BLACK: Sacramento Municipal Utility, Shannon Black.

MR. RUSSO: Any other S's?

MR. SERACK: San Diego Gas & Electric. This is Jan Serack.

MR. RUSSO: Can you spell that last name, Jan?

MR. SERACK: S-E-R-A-C-K.

MR. RUSSO: Thank you. Any other S's?

(No response.)

MR. RUSSO: T?

MS. HUDSON: Transcanada Power Marketing, and this is Carie Hudson, H-U-D-S-O-N.

MR. RUSSO: Thank you. Any other T's?

MS. HOWLAND: TXU Energy Trading.

MR. RUSSO: Could you repeat that?

MS. HOWLAND: TXU Energy Trading. Elizabeth Howland.

MS. SMITH: Tucson Electric Power, Denise Smith.

MR. RUSSO: Welcome. Any other T's? How about U?

MR. SHUBA: Utah Associated Municipal Power Systems, Tim Shuba, S-H-U-B as in boy--A.

MR. RUSSO: Welcome. V?

(No response.)

MR. RUSSO: W?

MR. REINHOLD: West Connect RTO, Charles Reinhold, R-E-I-N-H-O-L-D.

MR. RUSSO: Welcome.

MR. SINGER: Williams Energy Marketing and Trading, David Singer.

MR. RUSSO: Very good. Any other W's?

MR. SNOWDEN: Western Area Power Administration, William Snowden.

MR. RUSSO: Welcome. X? Y? Z? Anybody out there with those identifiers?

MR. HUDSON: Yes. This is X-EL Energy, David Hudson.

MR. RUSSO: Anybody else on the line that hasn't given us your name and organization?

MR. AHLSTEN: Eugene Water and Electric Board, Dean Ahlsten, A-H-L-S-T-E-N.

MR. RUSSO: Okay, very good.

MR. KATHEN: And David Kathen, K-A-T-H-E-N, from ICF.

MR. RUSSO: All right, David.

Okay, I think that's everybody. As I said before, this is really your opportunity to ask ICF Consulting and the staff any questions that you have on the report.

Who would like to go first?

MR. GUY: Baltimore Gas & Electric, Gary Guy. There was a question asked yesterday--I didn't ask it--but the people that were answering the questions were not able to provide the answer. So I just thought I would check and see if there is any update.

The question, as I recall, had to do with certain statements that were made in Order 888 and in the NOPR to Order 2000 about increased transmission capability, and that those projections--there was a 5 percent figure that was mentioned--are being assumed in this particular study by ICF.

The question was whether or not the staff had done any re-examination of that figure to verify the projections that were being made by the Commission.

Does that sound familiar?

MR. RUSSO: This is Tom Russo. That sounds very familiar to me. We are still looking into that at this time, so I don't have an answer for you.

MR. GUY: Thank you.

MR. WOLVERTON: This is Link Wolverton with the Industrial Customers of Northwest Utilities.

What did you do with the fixed-cost transmission revenue requirements that presumably are being paid for by a load?

MR. TURNURE: Yes. This is Jim Turnure at ICF

Consulting. I'll take a crack at that.

A number of people in these calls have asked about transmission revenues, and--can you hear me?

MR. WOLVERTON: Yes.

MR. TURNURE: Okay, the model we used carries only the costs in the utility sector that are relevant for either short-run operating decisions or longer term investment decisions.

One of the major cost categories that is not carried in the model itself is sunk capital, whether it's generation, transmission, or distribution capital. That is the sort of analysis which we often do as essentially asset valuation analysis.

But in this analysis, we did not incorporate the transmission revenue requirements directly. It would be the sort of thing that could be followed up on.

MR. WOLVERTON: May I ask a follow-up on that? Did you include tariff rates--

MR. RUSSO: Excuse me? Who is speaking?

MR. WOLVERTON: The same person, Link Wolverton.

MR. RUSSO: Thank you.

MR. WOLVERTON: ICNU. Did you include tariff rates in your scenario without RTOs?

MR. TURNURE: Well what we have in the model obviously for transmission, there's both the physical limits and the economic cost of transmission.

Under a normal forecasting situation, ICF Consultants carry estimates of tariffs for all the different links between all the different regions.

In this instance, the set of tariffs was replaced by what we call the implicit hurdle rates from the calibration exercise. That actually incorporates both tariffs that you can identify and really a set of implicit barriers to trade. And that is discussed more in the report, and I have had to explain it on these calls a few times.

So essentially the explicit tariffs are essentially buried in the Inter-Regional Hurdle Rates for this particular exercise.

MR. WOLVERTON: And as I--this is following on again--so there are no within-region tariff rates charged by the model at all?

MR. TURNURE: That's right. Because within a model region, it just acts as a single spot cooled centroid without that level of intra-regional transmission details. That would be something you would dial the model down to a more specific regional configuration to identify if that was something people wanted to do.

MR. WOLVERTON: And by using this hurdle rate and reducing basically, essentially reducing tariffs through that hurdle rate mechanism, or adjusting them, did you account in any way for the lost revenues from those--from reducing the hurdle rates?

MR. TURNURE: Well, no, because again generally speaking transmission revenue is a cost recovery type of mechanism, and that has to do with the front capital again. So that would be something that would need to be worked out as a follow-on exercise.

Generally speaking, it is our assumption that stranded costs of whatever sort are going to be recovered.

MR. RUSSO: This is Tom Russo. Those of you who are not speaking, can you press your mute button? It would definitely cut down on some of the static that we're hearing in the background. Thank you.

MR. HOFFMAN: This is Biff Hoffman from SRP. To follow up on the use of the hurdle rates, can you clarify for me the implications of the cases where you used a zero hurdle rate within an RTO? And specifically, does that imply that there would be no congestion costs within the RTO?

MR. TURNURE: Well, it is more a question of the scope of the study, really, than making a statement about congestion. The model at this level, at a national level of aggregation, essentially is not designed or intended to deal with real-time operational issues and the sorts of things you would analyze in more of an hourly power flow type of situation.

We have tried to be fairly clear that issues in the very short-run nature, including both congestion and things like market power, aren't included in this study and it could very well be the case that significant congestion within a region could change really how the dispatch operates, which would in the end change the net economic impact.

MR. HOFFMAN: Let me see if I understand. Say in the case where you ran a case for a single RTO and whole Western Interconnection, and you stacked the plants up in merit order to dispatch them, a plant in the Pacific Northwest would compete with a plant in the Southwest simply based on production costs, not withstanding where they were located or whether it was possible to get the energy from one place to another?

MR. TURNURE: Well you need to keep in mind that we're only talking about the economic side of the transmission grid. The physical transmission limits are not affected and stay there for all the regions, all the links between the regions as far as physical limits are concerned.

MR. HOFFMAN: But doesn't that affect the economies in production costs that you can achieve?

MR. TURNURE: In principle, yes, of course. The linkages between transmission and generation in general are very important, and the economics of transmission pricing can have significant effects in fact on dispatch in general, I would say.

MR. HOFFMAN: I guess the staff paper that came out Friday, for example, says the New York ISO runs a model very similar to what they're proposing, and they identify congestion costs of about $1.2 billion for the New York ISO.

Obviously a good chunk of the savings that you're looking for are savings that are a result of reducing congestion costs, and I guess the question is whether by reducing the hurdle rate to zero that implies an implicit assumption that that $1.2 billion of congestion costs would go away?

MR. TURNURE: I guess I'm not really sure. I don't think that they're really consistent problems in the way that we've handled this.

Obviously within a particular model's sub-region, which doesn't have transmission represented in it, the whole issue of where congestion costs arise and how much they are really worth simply is not visible at this level. So again that's really a question where you have to break it down and have some resolution, if you will, of the links and the potential for congestion within a region.

We've tried to model regions at least on transmission bottlenecks that are really large and persistent, so we've probably captured a good deal of that within, for instance, breaking up New York into different regions.

Clearly if those physical limits are still binding, you're having a congestion cost that's reflected in the different dispatch there. So we would be reflecting for instance in New York the differences between upstate and downstate and New York City as far as the physical congestion was concerned.

So I guess I'm just not totally sure quantitatively how much of that we would be picking up by preserving the physical limits, and how much of it you would have to do some further nodal or zonal pricing for.

I hope that is somewhat helpful. So maybe more follow up is required on that.

MR. RUSSO: This is Tom Russo. I think the working paper you're referring to was the Standard Market Design Working Paper. Is that correct?

MR. HOFFMAN: Yes, that's correct.

MR. RUSSO: Okay.

MR. HOFFMAN: I guess I'm trying to figure out how the model worked, and I thought I understood that it basically worked like one big pool where, if you had an RTO all of the generating units in that RTO would be dispatched according to merit order. And then whatever the total production costs for the region seemed to be, that would end up being the production costs for that case. And then you would compare that to the base case.

And I guess what I'm hearing is you can't deal with the transmission congestion in the entire Western Interconnection under the single RTO case?

MR. TURNURE: Well, this is Jim Turnure at ICF again. The only thing here is, yes, there is congestion because of the physical limits. The trick is that it is unclear what the aggregation into, you know, having several regions in the West rather than every single link represented, it's unclear how much of that aggregation causes a loss of information.

Basically, if you imagine the West with no physical transfer limits at all, then you would have one big spot pool that dispatched one plant against the other anywhere in the West.

However, we do have the physical transfer limits between the Western subregions even when it is one big RTO. So you could take, for example, you could eliminate those transfer limits and make them infinite, and then you would have a pure dispatch within the Western RTO. And then you could compare that to what happens when we have the physical transfer links. And that would partially answer the question of how much congestion we're picking up.

We are picking up, I think, the significant congestion. It's obviously not every single link. And the question is: What's the difference between the links we have and every single link? Does that help a little bit?

MR. MARCUS: Dave Marcus for the IBEW. In particular do you know if you were modeling the Path 15 congestion point, which is an intra sub-region congestion point?

MR. TURNURE: Yes. Path 15 in general I would argue is represented as the links between PAC Northwest and Southern California, especially.

MR. MARCUS: Well it's not on them. It isn't. It is between Northern and Southern California. The DC intertie goes directly from the PAC Northwest to Southern California and doesn't go through Path 15.

MR. TURNURE: Oh, I'm sorry. Yes, that's what I meant. If you look at the maps of the Western Regional Flows, you will see one arrow that swings way out. It looks like it's in the ocean. That's the direct DC tie.

MR. MARCUS: But that's not what I'm asking about. I'm not asking about that. That is an inter-regional link. I am asking about Path 15, which is the--

MR. TURNURE: Yes, between the--

(Both talking at the same time.)

MR. TURNURE: Yes, that's represented.

MR. MARCUS: Okay.

MR. WOLVERTON: This is Link Wolverton from ICNU. How do you handle real power losses?

MR. TURNURE: Real power losses are actually not directly represented in this model. And that again, you know, we at ICF believe you have to use the right tools for the right job. And we actually would in some circumstances for more detailed reliability studies, we use Power World for instance, and we also use GE MAPS from time to time. That's the sort of issue of reactive power losses, if that's what you're talking about, which you really have to have all of the Kershoff's Law's Equations, and the real power flows.

MR. O'MERA: This is Kevin O'Mera from Public Power Council as a follow up. You concluded as part of the study that California will be importing a lot more power from the Northwest, which one assumes since it's the longer distance is going to make losses go up.

Did you reflect those increased losses in your analysis?

MR. TURNURE: Yes. We have essentially a simplified representation of line losses. I mean it's a pretty simple approach to that issue, but we do in fact represent that for the different links.

That might be something to add to the plate of further information for people to get, because I don't think that's the level of technical detail that the study really gets to.

MR. RUSSO: This is Tom Russo. Let me just sort of add a note on what Jim just suggested.

As I said before, this is the last teleconference that we're holding. But in previous teleconferences a number of--many questions came to us dealing with the assumptions used, and specific questions dealing with, well what factor did you use?

What we are putting together now is what we're calling an Assumptions Package, which we plan on making available to everybody. It will be on our web site, we hope, by tomorrow. And this may answer quite a few of your questions.

If you don't see your questions answered in that Assumptions Package, then by all means state that in your comments or your request for additional studies, which are one and the same thing.

Additional questions?

MR. WOLVERTON: This is Link Wolverton from ICNU again. In that regard, would it be possible to submit some questions in advance before the Monday technical session that you could be prepared to answer?

MR. RUSSO: We haven't done this before, but I don't see why not. I mean, if you have specific questions right now that you would like answered.

MR. WOLVERTON: So if we were to submit those, say, to--if you could give us an address to e-mail those to say maybe by close of business on Thursday?

MR. RUSSO: Right. The only thing I could--I could--I don't--whether or not we'll be able to answer these depends upon just how much work it is going to take. Obviously if we have the answers on hand, we will be very happy to respond to you. All right?

And I can give you my e-mail address. You can send those to me. Ready?

MR. WOLVERTON: Ready.

MR. RUSSO: Thomas.Russo, R-U-S-S-O, as in Oscar, at ferc.gov.

Additional questions?

MR. SNOWDEN: Yes. This is Bill Snowden with Western Area Power Administration.

Could you tell me how hydro resources in the West were modeled? Were they modeled simply as limited energy resources used to essentially shave the peak for the loads? Or were they dispatched with various environmental constraints that we face today?

MR. TURNURE: Yes. This is Jim Turnure at ICF

Consulting. The way we deal with hydro actually reflects the distinction between run-of-river hydro and reservoir capacity.

Essentially we have two-part hydro dispatch. Part of it is considered must-run because of the scheduling and when it has to run and when it can't run. Some of it is considered dispatchable, and that would often be dispatched against peak in order to reduce overall dispatch costs.

But it doesn't have to be. The model can dispatch the dispatchable portion of hydro whenever it makes the most economic sense to do that. That would be a more detailed regional, sort of region by region breakdown between each region as far as what is dispatchable and what is not. And that would be some kind of follow-up, if you would be interested in seeing more about that. But that is the basic structure we're using.

MR. SNOWDEN: Okay. So essentially you've established a run-of-river or minimum release constraint, and then dispatched the rest to minimize production cost?

MR. TURNURE: Yes, that's right. And it all has to do with more regionally detailed assessments of who is really constrained, and into what seasons, and even what really demand period may be constrained into.

MR. WOLVERTON: This is Link wolverton from ICNU again regarding that hydro issue.

Are you--is the model capable of making decisions about whether to store hydro for delivery into later markets that might be more lucrative? Or is it mainly instantaneous?

MR. TURNURE: My impression is that it's largely instantaneous within a season, but I would have to check to be sure. Could you add that to your technical questions, because I think that would be something we could easily answer.

(Pause.)

MR. WOLVERTON: This is Link Wolverton again on a different topic. I have a concern that when you're measuring the with-case and the without-case and comparing costs of both, and the with-case simply eliminates certain costs that people are paying now--basically the hurdles, the cost of the hurdles--these costs do not evaporate of course; they just get transferred to someone else, somebody else's pocket.

But my concern is that you're comparing apples and oranges when you're comparing these two numbers; that you do have to make a reconciliation as to what losses you are--what basically the revenue requirements that would come from collecting hurdle rates that disappear.

And so I think that it is a fundamental

shortcoming of the way the--not the modeling, but the way the model is interpreted.

MR. TURNURE: Well, this is Jim Turnure, and I think that the important thing about that is that there are a lot of barriers to inter-regional trade which are not related to explicit transmission charges, and which have a lot more to do with informational problems, actual monopolistic gaming of the system, the calling of TLRs and other congestion measures, and a host of rather mysterious almost institutional barriers to trade.

The Commission talked about those at length in the original Rulemaking, and essentially this hurdle rate is almost a pure modeling exercise to force the model to dispatch regions according to how they actually dispatched in the year 2000.

Now what that leaves on the table is a whole bunch of economic transactions that could have occurred that year and didn't, and they are not all related to explicit transmission tariffs.

Now you can talk about the revenue losses from transmission, but if you calculated the revenues from these hurdle rates you would have a much, much higher number than you would get if you just calculated straight transmission revenues.

I'll wait for a follow-up, because I'm imagining you've probably got one.

MR. WOLVERTON: Well, yes. That was just a comment. I think that you still have the apples and oranges problem.

A second comment with regard to the West is, the West has had a kind of active power trading market now for 25 to 30 years. And the amount of withholding seems to be, at least from the experience of people out here, is very little. I mean we're trading power from the Pacific Northwest into the Desert Southwest; we're trading into California all the time.

And to say that there are economic transactions that are not being made seems to me a fairer oversimplification of how rich these power markets are out here.

MR. MARCUS: Dave Marcus, IBEW. Following up on that thought, did I understand Mr. Russo to be saying that the model was configured so as to recreate failures to trade that you believe occurred historically, and then the results of integration, of greater RTOs has been those past barriers disappear?

MR. TURNURE: This is actually Jim Turnure and not Tom Russo who made that comment, and the answer is: Yes. That's indeed exactly what we did, looking at the historic data as far as how regions actually dispatched versus what might have been an optimal dispatch for that year.

MR. MARCUS: This sounds like a classic case of what I call models that know too much, where the model thinks that there's things that the real world is not finding.

The trouble with assuming you can fix it is what makes you think that changing the system will make whatever is causing that friction to occur in the first place to go away.

MR. TURNURE: And while that is--this is Jim Turnure again--

MR. MARCUS: If you don't know why the failures to trade occurred in the past, how do you know you're going to get rid of them in the future?

MR. TURNURE: Yes. This is Jim Turnure again. I mean the Commission staff may wish to address that, but again the sort of logical basis for that has been laid out now for quite some time, and it is a question of whether people think that is the case or not.

We have simply tried to analyze the magnitude of effects that would occur were this type of RTO structure to be the way to get around some of these barriers to trade. Maybe the Commission can make some statements about that, either now or in the future, but that is essentially the case that is being made here.

MR. MARCUS: But you haven't actually modeled the causes of past failures to trade. You've merely constructed the model so that it will duplicate--is that correct--the past failures to trade?

MR. TURNURE: Yes. If you want to get into the list of complaints and actions and other market investigations that's gone on to document the various sources of these inefficiencies, there is--some of that is summarized in the report, and it points to the FERC staff investigations, the discussions. There are dozens, or hundreds.

Now the question of what is anecdotal evidence versus what's some other kind of evidence is of course very relevant, but the fact is there are mountains of evidence about these kinds of inefficiencies and market complaints.

MR. HOFFMAN: Biff Hoffman. Kind of a related question, if you were able to get the model to replicate history--and by that I mean the year 2000--to within plus or minus 5 percent, which I think is what the report said, and the output of the model gives you results that are in some cases less than a one percent improvement, is there any way to know what consonance we should place in the results? Or how we know that's not just within the noise level?

MR. TURNURE: Yes. This is Jim turnure, and that question has been raised in a couple of different ways in these conference calls.

I guess I would have to say, point one, that this is not a--in order to get a real sort of confidence level or some kind of probablistic assessment, you would be doing a lot more runs and you would be looking for indeed that exact kind of issue: How sensitive is this to the particular assumption? At what point do you sort of sort out the signal from the noise, if you will?

These models these days are fast enough that you can do the numbers of runs required to get more like a statistical confidence approach to the issues.

In this case, this is really what we're calling scenario analysis, which is much more of a collection of assumptions married together sort of an approach. And I guess I'd have to say people are going to have to draw their own conclusions based on what really is a very limited scope and limited number of runs.

I am hearing a lot of people ask for more sensitivities and variations in the key drivers of these results, but the model is, you know, rather stable as far as directionally which way it's going to go under these FERC assumptions.

I mean I think it's a fairly almost predictable directional result, but the regional and more specific quantitative details, a lot of that remains to be combed over in my personal view.

MR. REINHOLD: This is Charles Reinhold with West Connect. The study results show a fairly substantial benefit to be gained from demand reductions, but it appears to me that it's kind of a general assumption that consumers will react to high prices and reduced demand on their own.

Does the model itself have any kind of sophisticated analysis of the state mechanisms involved which translate the wholesale prices into actual reduced demand in various regions?

MR. TURNURE: Well, this is Jim Turnure at ICF. I'll start to answer that, and then I'll actually ask Dave Kathen to say some things, because he has been doing a lot of Demand Response work over the years and is doing a lot more right now for NARUC and for other folks.

Let me make a general point about pricing in the model. The way we're doing the pricing is essentially just to wholesale spot market pricing. There has been--we have developed modules for this model that can actually do customer class-specific and demand-segment-specific pricing. That's a very complex piece of the model which frankly we don't have good elasticity data to support. That's been there for years.

But what we're doing in this instance is a much more, I would say, transparent as well as simpler approach to the issue in which we did some offline statistical analysis and carried the results into the model as an exogenous assumption.

And Dave can explain a little bit more about what we actually did there.

MR. KATHEN: This is David Kathen from ICF. What we essentially did was assume a price elasticity response and making an assumption that there is by, I forget, is it 2006, there will be a transfer of a price elastic or a price responsive type programs to customers.

We're assuming 50 percent of the customers will have some means of having variable pricing, of which there will be then demand elasticity. And the demand elasticity was assumed to be negative point one, and that results into a 3.5 percent reduction in the peak demand. And we assume that across all regions.

MR. O'MERA: This is Kevin O'Mera, Public Power Council, for a follow-up. Could you explain what the role of the RTO is relative to this Demand Response program? I mean why is the existence of the RTO a precondition for doing this?

MR. TURNURE: Well the Commission--this is Jim Turnure again--the Commission staff may want to say a few words about this, just because there has been a recent white paper on this topic that the Commission staff put out, which

I want to say the most recent version was issued in December, but I could be wrong about that.

Essentially the role of the RTO, the Commission has made a lot of statements in general about improved market performance. It's also fairly clear from the work that's going on on market monitoring and mitigation that Demand Response programs can offer a lot of protection, if you will, against short-term market imbalances.

Again, this study in general is attempting to categorize and quantitatively assess the relative magnitudes of these different types of benefits. And clearly Demand Response is a big driver.

But within that, how RTOs are going to hook into Demand Response programs, all I can say is there's a lot of interest in that, and it rapidly gets into a policy domain that I'm not really commenting on in this context.

MR. RUSSO: This is Tom Russo. Let me say a couple of words on this.

Those of you who have read the Working Paper on Standard Market Design, which was issued last Friday, know that Demand Response programs are really a key component of the Standard Market Design proposals and the rulemaking that we're contemplating.

We hosted a conference with the Department of

Energy on February 14th, and that was really the beginning of a lot of changed thinking around here on what the role of Demand Response is in the electricity markets.

We've come away from that conference thinking that to focus only on a supply option is just not the way to be going. And so as a result of the February 14 conference, we certainly believe that Demand Response has to be a key component of Standard Market Design.

Whether or not the role of an RTO propels that, accelerates that, is sort of an open question. And this is just a personal opinion here. Some might argue that, well, an RTO is really not needed to really propel Demand Response to what it should be, but Standard Market Design certainly is the vehicle to make that happen.

MR. WOLVERTON: This is Link Wolverton from ICNU. Could you--I mean that clearly bumps on a lot of Commission-State Commission decisions, because Demand Response tends to be a retail decision.

What was the reaction of the Commissioners to basically the RTO asserting what might arguably be called a retail ratemaking prerogative?

MR. TURNURE: I don't know--who wants to respond to that? This is Jim at ICF, but I can make one quick comment on that, and then I think the staff probably has a few things to say.

My perception from being on all the calls last week was that they mostly wanted to clarify what structural market assumptions we were making. And I think we clarified that the wholesale prices could be fed through to retail customers by fully integrated utilities, and in fact there are many utilities right now that have such price signal programs.

Their main concern was that we weren't assuming as a prerequisite that there be retail access, strictly speaking, in order for there to be pricing.

Beyond that, the Commission can let you know about the transcripts of those calls, and there will be comments that reflect really what the states actually think rather than our paraphrasing it.

MR. RUSSO: Yes. This is Tom Russo. I agree. I mean I was present at all of the meetings, and I am really struggling hard to recall what specific teleconferences and Commissioners had concerns. Sorry I can't be more responsive on that. But you just have to wait for the transcripts to get a better idea.

MR. TURNURE: Do you want to tell them about that availability of transcripts? I'm not sure that was mentioned before in this call.

MR. RUSSO: Yes. The transcripts, all of the transcripts, with the exception of this one right now, are available from Ace Reporting. Of course they'll charge you for those transcripts, if you want them immediately. But generally the policy here is that we make them available on our web site ten days after a meeting.

So for example the Midwest--the Western State Commissioners meeting took place March 15th, so about March 25th or 26th that transcript should be available on our web site.

Okay, additional questions?

MR. HOFFMAN: Yes, this is Biff Hoffman again from SRP. Can we move on to how native load was treated, and specifically I think most of the generation in the West goes directly from generation to retail bypassing the middleman, if you will, of the wholesale market.

Would that--and if I understand the way the study was done, the presumption would be that all energy was basically cleared on marginal--short-run marginal costs.

How would the fact that most of the generation is outside of the market and directly serves native load impact the results of this?

MR. TURNURE: This is Jim Turner again at ICF.

This question came up a lot during the state calls, as I'm sure you can imagine, and was raised quite a lot by the state commissioners who participated in framing the issues for the study in the first place.

Essentially the whole debate here revolves around how a native load requirement or a native load practice of any sort would affect competitive economic dispatch of units within a region.

You can think of native load as a set of contract requirements. We do have the capability to model contracts. We often do that, for instance, for must-run units, whether they're sort of requirements' contracts, or QF type must-run units, or reliability must-run units.

In essence you'd have to posit the question: Does the native load requirement change or interfere with the economic dispatch results? And we in the end took the approach, and in fact our wholesale practice normally takes the approach, that the competitive dispatch is not affected by native load requirements.

In other words, there is no inefficiency introduced by the native load requirements. That's not the only way you could approach this issue, but we do believe it is one consistent and plausible approach to the issue, and that is something which people may choose to do more follow-up work on. And I'm sure there's going to be some follow-up questions about that, too.

(Pause.)

MR. HOFFMAN: I guess there aren't any other questions. I have a question on a different topic. This is

Biff Hoffman again.

Is it accurate to say that it is not possible to reach a conclusion from this study about the differences in reliability between the cases that were modeled? Is that a fair conclusion?

MR. TURNURE: Well--this is Jim Turnure--all you can say from this study is that the long-term reserve margin requirements of all the regions are met in all the cases. That's the constraint in the model. It actually would not ever fail to meet that constraint.

If you wanted to look at the flow changes and the detailed issues of, for example, disaggregating the links to get a better look at the thermal transfer limits, you would really need to use a more detailed system to take a look at that.

Now of course there is no detailed system that can simulate the system over a 20-year period. So you have to pick which hours and which years and which you would like to simulate that with more accurate detail, but that is the kind of follow-on work that I think we would more or less recommend. And I think the study pretty accurately points to that as an important issue for people to take a look at.

I mean there's both the aggregation issue and the direct power flow modeling issue.

MR. HOFFMAN: I guess if someone were to say the

ICF study proves that reliability is improved with RTOs, that would be over-reaching. And, conversely, if they say the ICF study proves that reliability would deteriorate with RTOs, that would be over-reaching also? Is that correct?

MR. TURNURE: This is Jim Turnure at ICF. I mean while I hesitate to use the word "proof" really in any social science context, yes, I do think that making broad firm generalizations about that would be over-reaching, with the exception that we're trying to look at the benefits of improving sharing of capacity and reserve margins across regions.

So that is sort of a sub-set, but it is certainly not the whole story with reliability at all. And I would argue that we're pretty far from getting to that sort of very detailed look at reliability.

So, yes, in general I would agree with your statement.

MR. WOLVERTON: This is Link Wolverton. A question on another topic on the improvements in the efficiencies of also-fired units by 2010, 6 percent. Where does that number come from?

MR. TURNURE: That is cited back to earlier national analyses of electric power competition. I could characterize the approaches that other studies have used when approaching this issue. It really revolves around best-practice analysis, and allowing units with poorer performance to approach the performance of better units.

But I also would point out that that's one of the things that we're preparing in this assumptions' document which is in progress right now and should be available tomorrow.

It won't be everything that answers everyone's questions, but it will point further to how that type of really statistical analysis is generally done. We did not reduplicate that analysis for this study. We used pre-existing sources for that, and we can track that back and explain how it was done previously.

MR. HUNTOON: This is Steve Huntoon with Dynegy. I have a question about, I think a related question on the RTO policy case.

In terms of the improvement in generation unit availability that is projected under that case, is the assumption that there is a gain of 2.5 percent annually from 2004 to 2010? Or a total gain over those years of 2.5 percent?

MR. TURNURE: It's the latter--this is Jim Turnure again--it's the latter. That is the total improvement in availability. It's not a percentage annual rate.

MR. HUNTOON: And how did you handle that over the 2004 to 2010 period? Was it phased in?

MR. TURNURE: Actually I believe that is a one-time, one-year improvement just like the 5 percent increase in thermal transfer limits.

MR. HUNTOON: So you would--

MR. TURNURE: And that would--

MR. HUNTOON: --have put it in for 2004, and then just assumed it would have been assumed to be recurring? I mean the same assumption, assumed to be true of all the other years?

MR. TURNURE: I'm sorry? Could you repeat that?

MR. HUNTOON: Would 2004 have been the year in which you put 2.5 percent improvement in for the first time, and then it just continued to be part of the study for each succeeding year?

MR. TURNURE: I believe that's the case, yes. And I would also say that that assumption is also one of the ones that we're putting some further documentation together for.

MR. HUNTOON: I have another similar clarification question, if I could. On the Demand Response case, there is an assumption of a 3.5 percent reduction in peak generation. But page 37 of the study says that that reduction is assumed to be beginning in 2004. But Table 2.1 indicates that the assumption is starting in 2006.

So I am wondering if you might be able to address that and clarify which year that might be.

MR. TURNURE: Yes. Sure. We'd be happy to do that. I'm going to make sure that we've covered all that in a lot of detail. Obviously that's a contradiction within the study and we'll just reconcile that and make sure everybody has the accurate information there.

Dave was recalling 2006--

MR. HUNTOON: Could I ask one--I have a third area of questions, if I might, that's not in the nature of clarification but to try to understand the methodological approach that was used here.

Just to try to get clarity around it, and you probably answered this question before, but this is the first call I've been on and been able to ask a question like this.

Is it correct to say that the study does not assume any gains associated with an RTO policy within any of the 32 regions themselves?

MR. TURNURE: This is Jim Turnure again. That's an interesting question. There are no transmission related gains within the regions themselves because there's no representation of transmission within those 32 regions, within the most disaggregate regions for this analysis.

The generator and demand response improvements of course apply to the generators, and they are within the regions. But the transmission side, you are correct that there aren't any further benefits assumed inside regions.

MR. HUNTOON: So just to make sure I understand the answer, let's take the Southern ECAR Region, which I think is one of the 32 regions for example. Putting aside the generation--as you point out, there are generator gains that are assumed to be occurring for all generation, I guess, but in terms of more efficient dispatch of units, for example, within that region there is no gain associated with that in the study?

MR. TURNURE: Right. In terms of dispatch, that's quite correct. The units in the--the base case dispatches within regions on a competitive efficient basis and it continues to do so.

I would also point out the reserve margin reduction is also a benefit that would accrue within a region. But that reflects sharing of reserves across regions and that sort of thing. But the dispatch, per se, is not affected, at least the mechanism, the market mechanism, is not affected.

MR. HUNTOON: So if you had pancaking, for example, within the Southern ECAR Region that may create less than optimal generation unit dispatch, and an RTO were to eliminate that or reduce that, that is an example of a gain that is perhaps not being captured here? Is that true?

MR. TURNURE: You could say that. Again, there's an aggregation issue here, and it is unclear what the magnitude of that effect would be.

Generally we try to break the regions up according to significant transmission bottlenecks. So a lot of that type of issue is handled in the breakdown of the 32 regions themselves.

However, I can also tell you that when ICF does market forecasting we incorporate tariffs to get from the middle to the edge of any particular region, and Southern ECAR is one where we would have included some pancaking of rates to get to the edge of ECAR from the middle of it.

That was essentially replaced by this calibration and hurdle rate approach for this study.

MR. HUNTOON: Now let me ask you--first of all, I would like to draw a distinction, if I could, between physical constraints and financial hurdles, or inefficiencies that may be attributable to financial hurdles like rate pancaking.

MR. TURNURE: Yes. That's a very important distinction which is very related to how the model actually structures the transmission.

MR. HUNTOON: Okay, so now if we can draw that distinction and put the physical aspects of this aside and focus in on rate pancaking, I'm not sure I understood the last part of your answer where you--what is it in your model that would have captured more efficient generation dispatch within something like Southern ECAR from the financial pancaking standpoint? I didn't understand what you were saying about that.

MR. TURNURE: Oh, well this is Jim Turnure at ICF. Essentially we're only looking at the transfers between the regions, so I think it would be accurate to say that efficient dispatch of all the units within Southern ECAR is a structural feature of the model when you've got this level of regional breakdown.

And a lot of times we break things down further for compliance and a kind of more detailed analysis that people would be interested [there is much interference in this telephone line] in for reliability purposes would be equally applicable here. The question being essentially pancaking is a lot like congestion once (inaudible).

THE REPORTER: I'm sorry, I cannot hear him.

MR. RUSSO: Jim--

MR. TURNURE: --dispatch--

MR. RUSSO: Jim, excuse me, this is Tom Russo. We can't hear you. If anybody has their mute button on, could you please press it--I mean, turn it on?

Jim, could you repeat the last sentence that you stated?

MR. TURNURE: All I was saying was that we do in fact dispatch Southern ECAR as one efficient spot market under these regional aggregations. And so your point is quite correct that any rate pancaking that affects the dispatch inside a region, Southern ECAR, is not reflected in this configuration of the model.

MR. HUNTOON: Okay. Thanks.

MS. WHISTLER: This is Laura Whistler with Salt River Project. I know that in our region there is already a reserve-sharing arrangement in place among generators, and I wanted to know if your model recognized reserve-sharing arrangements that are in place, and is showing improvements over and above that? Or did they not model those contracts that are out there already?

MR. TURNURE: This is Jim Turnure at ICF. There generally isn't a contract-specific representation of that. That would be picked up in the regional reserve margins, to the extent that the reliability councils in the regions have taken account of those kinds of programs will have taken account of it too, because we are adopting their reserve margin requirements initially.

Then secondly, I would say that, yes, on a consistent region-by-region basis we are applying a uniform set of assumptions that does in fact represent additional improvements. And so there could very well be some issue with that in your particular case, and I would just say that we picked up existing reserve-sharing agreements to the degree they're reflected in current reliability requirements for your area.

But we are assuming further improvements.

MR. WOLVERTON: This is Link Wolverton ICNU. Would you clarify that? Because I thought you said--it seems to me you're assuming a 15 percent reserve margin where everybody gets to anyway. What if a region is already at 13? Do you drop it to 11? Or how do you handle that?

MR. TURNURE: I think you will see some detailed look at the reserve margins by regions in the Assumptions Document. You can take a look at that yourself.

Generally speaking, we would not force reserve margins upwards. I think that we intend it to mean that there's a regional, an average, if you will, that you end up close to, as opposed to every region having the same.

MR. MARCUS: Dave Marcus, IBEW. In any of your scenarios did you ever look at the possibility that you would want and/or need a higher reserve margin to preserve wholesale competition?

MR. TURNURE: Oh, that's a great question. This is Jim Turnure again. You know, as you look over the last few years and you take into account a lot of people's thinking and research on market power and market structure, the concept of an economic reserve margin has been introduced and is a real interesting idea.

Again, we are in a--we are modeling a market structure over a 20-year period in an equilibrium framework, so we are not assuming the kinds of market structure problems that would lead you to talk about an economic reserve margin.

Furthermore, just as a matter of theory, there's a number of ways out of structural vulnerability in a market, and more supply is only one of them. Demand Response is another. Market deconcentration is yet another.

So it is unclear that there is a clear answer to that economic reserve margin question, but just on the most basic level we are not incorporating that because we're not incorporating some of these short-term market disequilibria and market power problems.

I think we have tried to say that pretty clearly.

MR. HUNTOON: This is Steve Huntoon, if I might ask a last question. The study refers to prior studies, including one that was called The Supporting Analysis For The Comprehensive Electricity Competition Act of 1999, which indicated benefits of competition in the $32 billion a year range, and your study summarizes that.

Although that study back in 1999 ostensibly was looking at competition, wholesale and retail, when you really drilled down to that study it looks as if the only thing that is being assumed about retail competition is that the benefits of competition are passed through at the retail level. Which I guess is somewhat--something that is sort of assumed here, as well.

But you can comment on that preface that I just gave to my question, but my question also is:

Have you tried to figure out why there is such an order of magnitude difference between the $32 billion in that study and the results that you have on, let's take on the RTO policy case, and what comments you have on that?

MR. TURNURE: Yes--this is Jim Turnure at ICF. You know, actually we were asked at the Commission hearing on the 27th what the impact of these changes would be on consumers, and we were not doing that as part of this exercise. So we are not making presumptions about what happens to, you know, customers, as a result of these changes in production costs or wholesale energy prices, for that matter, just to make that clear.

I would say that if you look at that analysis that the Energy Department did, there are a lot of similarities in terms of modeling and methods. They used what is called the POEMS model. It's the Policy Office Electricity Modeling System. It's kind of a replacement module for the Electricity Market Module in the NEMS System.

That is a pretty detailed model. It's actually operating at the control-area level, so in principle they're running maybe 100, 120 distinct regions in that model. They also have a lot of time details, demand segment detail.

Other than that, though, it still uses a transportation representation for transmission links, and a lot of the details of dispatch and dynamics in terms of investment and so forth are very similar to the type of model we're using.

I would consider them quite related systems. Essentially, I believe that what you would find if you took those analyses apart and laid them out side by side would be that this is an assumption-driven difference in magnitude of the ultimate benefits.

It would take a sensitivity analysis, I think, to disentangle exactly which assumptions were which, and I have not done a side-by-side of those assumptions. But I am sure that that is the driver of, you know, our study only reaching as much as $10 billion a year, and theirs reaching $32 billion a year. It is a similar framework.

MR. HUNTOON: I would throw out the possibility that, because they go down the control area that they are capturing potential benefits that are not captured at the 32 region--at the level of 32 regions.

MR. TURNURE: That is one possible--

MR. HUNTOON: That's just an observation I have without any quantitative support for that, but in reading the two studies it seems like that might be a significant difference.

I also wondered, just one follow-up, there was a study about five months later after the supporting analysis was reached that was actually done by EIA, which was asked to run the supporting analysis through the EIA's NEMS model, and using the supporting analysis assumptions. I mean they were asked to take those as a given. And they got very similar results as the supporting analysis.

And I was wondering if you all had looked at that piece of work by EIA, as well?

MR. TURNURE: You know what, I think we missed that one. Why don't you give me the reference, if you've got it handy.

MR. HUNTOON: If you give me your e-mail, I'm going to have to dig out the Internet web site address and I will be happy to e-mail the reference to you, Jim.

MR. TURNURE: No, that's okay. I can find it on their web site.

MR. HUNTOON: Okay. If you have a problem, and it is a little bit obscure--as you know, they revamp EIA web site all the time--you can send me an e-mail at steve.huntoon@dynegy.com and I'll send it to you.

Thank you.

MR. TURNURE: Okay. And I guess I could make one further comment, which is I can't say this with certainty, but I would be willing to guess pretty strongly that it is less likely to be an aggregation issue in terms of control areas versus 32 regions, and it is probably a lot more driven by their assumptions about generator efficiency and demand and so forth.

I'm just going to put my guessing hat on and make that assumption, because there's another study that's coming up soon which is the National Grid Study that the Energy Department is preparing at the time right now, and they are changing transmission assumptions with a fair amount of detail. And again it reflects the relative magnitude of those differences between the SECA analysis and what we just did. It almost has to be related to power plant assumptions, it's just that big.

MR. RUSSO: This is Tom Russo. Any additional questions or comments?

MR. DAVIS: Yes. This is Alan Davis from PP&L Montana. If you notice your map on page 68, my question is about the regional differences.

It shows Montana really sticking out in terms of increasing power prices.

MR. TURNURE: Yes. Is that a question?

MR. DAVIS: Well I just wondered if you could explain that a little better. I think the confusion that everybody in this region is having is you're generally modeling Montana Power Company, now what is called Northwestern Energy Service Territory, with the highest transmission rates in the region, a utility that's divested of generation so totally in the market, and trying to figure out how forming the RTO is going to increase power prices rather than increase and facilitate competition and provide consumers with more rather than less benefits.

MR. TURNURE: Okay. Well this is Jim Turnure, and let me take that apart into two pieces. One piece is: How could the energy prices within that region increase? And the other is: What are the broader economic implications of that? Because I don't think that's the end of the story.

Essentially what happens in an exercise like this is there's more inter-regional trade, and different regions have different levels of generation and different supply options.

You can think of them as supply stacks or supply curves. And it is just a coincidence of the database how each region is configured and when they move from lower cost to higher cost generation.

I mean it's just based on what the physical infrastructure of those regions happens to be. So for one region to export.

So for one region to export quite a bit of power and not have its prices go up, that could easily happen because it's moving along a flat supply curve which represents just having more large generators lying around ready to export.

Whereas, another region could export the same amount of power, or even less power, actually, and move up quite a bit on its supply curve just because it ran out of its lower-cost units and moved up to its higher-cost units.

So in this instance, that is what is happening. And I am not in a position to give out all those more detailed outputs that would sort of allow you to create the regional supply curves, but that is the sort of thing you could pull out, and people are asking for that kind of information.

So in other words, that is how this could happen. And I would point to related work by Eric Hearst in the Idaho context about, I'd say '98 or '99, and then the RTO West Study that Tabors, Caramanis & Associates is conducting right now. They're using a different modeling approach and coming up with broadly similar conclusions, with perhaps less magnitude.

But I recall them in their preliminary results having a price increase for the Montana region, as well. So it's really just a question of where you end up in your supply curve.

The question of what happens after that is actually extremely interesting. You can think of it as the question of export revenue coming back into the state. It almost has to be the case that there's actually more money in that region because they wouldn't export the power unless it was a higher value.

So technically there is more money coming in, and rather than just thinking of it as a producer surplus, what you would do in normal tax analysis, for instance, it really becomes a case of earnings for the producers and what happens to those earnings becomes a question of states, and market structures, and things like that.

So there's more to the story, in other words, and I think we try to suggest that towards the end of the study.

MR. MARCUS: Dave Marcus. But in the example he just gave where he's got a fully divested generation sector, no gains to generators will flow to retail customers in Montana. Right?

MR. TURNURE: Well, that depends on how you look at things like tax revenues and things like that, I suppose. Again, that's really an accounting exercise at that stage.

I mean that certainly could be the result, yes.

MR. DAVIS: My concern is that you haven't appropriately modeled what's really going on here, and the implications that you talk about are pretty pronounced as far as public policy. And Tabors has the exact same problem. And so I just wondered if there's some way of going in and looking at this particular piece a little more carefully just to make sure that you feel comfortable with modeling reality rather than just picking up what the model says.

MR. TURNURE: Do you mean in terms of potential native load requirements? Or just the details of the generator stock in that particular region?

MR. DAVIS: Just the generator stock, because I'm not convinced that the generator stock is entirely there in Montana, just because of the transmission systems. And so you're picking up basically hydro and coal, and that's it.

MR. TURNURE: Well I'm always open to suggestion of going in with more detail. I mean obviously this was a big analysis that covered a lot of regions, a lot of years, and a lot of scenario.

MR. DAVIS: And I understand that, and we are at the very end of the system here. But it is just a caution because it does--obviously when the decision makers see things like this on a map, the default reaction is very pronounced.

MR. RUSSO: This is Tom Russo. Who was just speaking?

MR. DAVIS: Alan Davis.

MR. RUSSO: Additional questions or comments?

MS. WHISTLER: This is Laura Whistler, with Salt River Project.

I am looking at the ICF report on page 40 where there's a discussion or reserve margin, and note that in the Northeast the reserve margins were modeled at close to 20 percent, starting out.

Do you know if the 20 percent reserve margins for the Northeast are mandated like in Florida? Question mark.

MR. TURNURE: Well, this is Jim Turnure. You know, the Reliability Councils generally set those reserve margins. There are some exceptions. You know, there's the 80 percent rule within New York City, and so on and so forth.

New York in particular has been, you know, extremely reliability conscious for decades. Since the New York blackouts and the events that really precipitated the development of the Reliability Councils, they've been extremely conservative in some ways on their reliability assumptions.

I would have to get back to you in terms of the documentation there, because again I generally know that we're operating off of the NERC documents. I don't believe there are legislative requirements per se, if that is what you are referring to.

MS. LIFLER: Well I was wondering what was the cause of what are for us here in the Southwest relatively high reserve margins at 20 percent. We don't operate to that high a reserve margin.

And my question was: If those are not mandated or set by the Reliability Council, I was curious as to why PJM for instance which has operated a tight power pool for many years, doesn't have a lower reserve requirement, or reserve margins.

There is a statement in your report that says, you know, the assumption is that pooling of generation resources are likely to occur within an RTO region. And if pooling has already been going on in PJM, for instance, and they still maintain a reserve margin of 20 percent, my thought is they're probably doing it because there's some mandate.

MR. TURNURE: Well these numbers for the Northeast are definitely Reliability Council numbers. And in general they'd be modeling system contingency and failure scenarios. And the question of exactly which ones they model is actually a very detailed question, because people take different (inaudible) conditions into account, and the question becomes what is the largest piece of your system that could fail?

And if you are talking about a large nuclear unit, or a major transmission tie-in, you can actually require a high reserve margin to cover that contingency. So that is the sort of process people go through. But these would definitely be sourced to NERC or the Sub-Regional Reliability Councils.

MR. HUNTOON: Well, could I ask--Steve Huntoon--could I ask where these reserve margins show up in the study? I mean, physically on the piece of paper? Which page is it that's being referred to, this 20 percent and whatnot.

MS. WHISTLER: This is Laura Whistler from Salt River Project. It is on page 40 of the ICF Study.

MR. HUNTOON: Thanks.

MR. TURNURE: Thanks.

MR. RUSSO: Additional comments or questions? We have plenty of time.

(Pause.)

No questions? Going once?

MR. HUNTOON: This is Steve Huntoon. I'm finding that section now.

MR. RUSSO: Okay. Take your time.

MR. HUNTOON: And the section talks about margins in the Northeast that begin closer to 20 percent in 2003. That is above the target reserve margin that, as I understand, exists for PJM and NISO, and I think one would have to look into the details of each of those two systems. And I also think they are larger than the actual reserve margins that exist right now.

So I cannot explain the number 20 percent, but I would not assume that that is because either PJM or the NISO has set a 20 percent reserve margin figure.

MR. MARCUS: Isn't there someone from NISO on this call?

THE REPORTER: Who is that?

MR. RUSSO: Who just spoke, please?

MR. MARCUS: Dave Marcus.

MR. RUSSO: I thought we did have somebody from NISO on the call. Hello?

MR. TURNURE: Well this is Jim Turner from ICF, and I am making notes about this. Any time there is a factual issue or a quality control issue, you can believe I'm putting little asterisks by my notes. So I am definitely going to make sure that that's indeed characterized the way I was saying.

(Pause.)

MR. RUSSO: This is Tom Russo. Any other

questions, please?

MR. HOFFMAN: This is Biff Hoffman. With respect to the improvements in the transmission system, I know the Western Governors Association's Transmission Study has been mentioned before, but in a little different context, in the Western Governors Association's Study they did a couple of runs.

One run would assume that most of the capacity additions were gas-fired generation, which in the West tends to be located near the load centers. And in that study, they figured that the transmission upgrade, if I recall right, that would be needed would be about $2 billion.

They did another run that assumed that most of the generation expansion would be lower cost coal resources, as well as some renewable resources. And that particular scenario, if I recall right, required something like $8- or $12 billion in capital upgrade.

In making the generation expansion--given that the ICF Study doesn't include any money for capital upgrades, and in fact assumes that there would be no capital upgrades on the transmission system, how do the generation expansion plans fit in in such a way that you've got the right mix of gas-fired generation versus coal?

MR. TURNURE: Yes, this is Jim Turnure. That raises a couple of really good issues, which have been raised before, but the way that we're handling this is we're leaving the major transmission assumptions alone. And this model can be used in a dynamic transmission expansion mode.

I mean, we can allow it to expand transmission on an economic basis. It's just that those transmission expansions are themselves so contentious that generally speaking it is considered more controversial and less, in a way, realistic to be allowing a lot of transmission links to be built throughout various regions. But we leave those static.

Now what does that mean? That means that generation has to be sited in such a way that it doesn't violate the existing set of transfer limits. So the physical constraints on the grid are actually going to change where the generation is located.

And if you did assume transmission upgrades of one sort or another, you might allow plants to be built someplace else. So that has a lot to do with it.

A small note I would make is that we are including some upgrade costs in the plant builds themselves. That is mostly interconnection type costs. It is not like system upgrades to the whole grid. But there is a small piece of that that is in the actual plant builds.

Beyond that, the other comment I would make is that the question of where the links are the most valuable, that is the type of study we do for clients. We will do, you know, either a sort of broad regional look at that, or we might take a specific line, or a merchant transmission project for instance.

And people have asked, I think in these calls, for some more looks at that issue. So that is something that is on the table.

MR. HOFFMAN: But I guess the question is: Would the results be different if your generation expansion consists mainly of gas-fired generation near load centers than it would be if your generation expansion consists largely of remotely located coal-fired units?

MR. TURNURE: Yes, probably, although to be honest the gas additions do tend to dominate this model in most cases. I mean it would take a lot of alterations to make new coal builds be a major portion of the mix.

But I think as a more general answer, if you allowed large changes to the transmission grid in the West, you would definitely have a different configuration of plant builds, even though they may still be mostly gas. So that is kind of how I would answer that at the moment.

I mean I'm not sure how the Western Governors Association got to their coal build scenario. I think they actually sort of assumed most of that, didn't they? Just to see what the transmission requirements would be?

MR. SHUBA: No. They basically asked people and looked at real plants that were put together.

MR. HOFFMAN: Well they also were taking a policy position that they didn't want all new generation to be just single-fuel reliance.

MR. TURNURE: Right. And another relevant point--

THE REPORTER: I don't know who the last two speakers were.

MR. RUSSO: Jim, excuse me for a minute--

MR. TURNURE: --just informationally is that-- modeling forum that just started in January. And the topic of this new Stanford Energy Modeling Forum is in fact fuel mix diversity as a hedge against natural gas supply shocks.

So they're looking at upstream natural gas supply potential price shocks and how a portfolio of different plant types or fuel could help to insulate against that sort of price shock. So that's just something people might want to know about, or go take a look at.

MR. SHUBA: I'm sorry, I didn't identify myself. This was tim Shuba that was referring to the Western Governors Policy decision.

MR. RUSSO: Thanks, Tim.

MR. SHUBA: Sorry. I heard you trying to get in there to get it.

MR. RUSSO: No problem.

MR. HUNTOON: This is Steve Huntoon. I keep having a last question, and I'm sorry, but, Jim, how sensitive is this model to projection to future natural gas prices?

MR. TURNURE: This is Jim Turnure at ICF. Essentially changes in future natural gas prices have to be pretty large before you trigger a different build mix. That can happen, for example, in climate change analysis, which this model is used for quite often.

However, changes in the gas price do affect both the mix of combustion turbines versus combined-cycle builds and of course it feeds directly into the production costs in the model.

That's a classic sensitivity analysis that people would often perform in scenarios like this.

MR. HUNTOON: Just one follow-up along those lines. When I looked back at the supporting analysis study, it seems as if one of the important assumptions that they make is that generation comes off of embedded average cost pricing--essentially cost of service regulation--and that generation becomes priced on a marginal-cost basis.

And then, when you do something like that, of course future natural gas prices can be an important driver of the results of the model, because natural gas was often at the margin, so to speak.

MR. TURNURE: Right.

MR. HUNTOON: And that marginal price is driving prices essentially for all generation.

Is it correct to say that your model does not assume marginal cost pricing for all generation, but assumes--I don't know how to say this--but the bulk of generation as remaining on traditional cost-of-service-based regulation?

Or, correct me, what mistakes am I making in that proposition?

MR. TURNURE: Well, this is Jim Turnure. In fact, you know, we really only used marginal cost pricing. To the degree that the DOE study was starting from a different pricing mechanism, that's a pretty big difference in the study.

We're pricing each demand segment as a marginal clearing mechanism. Okay? So some of those demand segments in the very low demand periods are fairly cheap, and others are much more expensive. And natural gas at some point enters--

(Static background noise is quite pronounced.)

MR. TURNURE: --into that and drives, I would say, most of those demand segments in the marginal pricing regard. But all of the energy price outputs in this model are built up out of marginal pricing of both energy and capacity.

MR. HUNTOON: Well let me just ask a question because that's sort of--I'm not sure how that's happening with your model, because the status quo, I mean sort of what you're starting with in the year 2000, whatever your baseline is, is most generation is traditional cost-of-service based regulated generation that is showing up ultimately of course in the bills of end-use consumers.

Now how do you change that to reflect, to become marginal cost pricing of generation?

MR. TURNURE: Well essentially that's why we have both production costs and energy prices as two separate outputs. Just because the spot price on wholesale is set by marginal cost pricing, that may not have anything to do with what the ratepayers in the region are experiencing.

And you can take the production costs in a region and parse those out to ratepayers as a pricing mechanism, or you can take the regional wholesale marginal energy price and feed that back down to the consumer.

So really you've got a choice and both types of information are produced by the model. So a lot of plants are running in a demand segment when the price is considerably above their production costs, but you can actually just go take the production costs.

MR. HUNTOON: When you say "in the demand segment," you're talking about the demand response piece of your study?

MR. TURNURE: No, I'm just saying that in each region the demand is broken down into 10 segments, from low to high demand. So each of those segments is priced separately.

MR. HUNTOON: Help me understand what you're talking about the difference between the production cost component and the energy cost component.

MR. TURNURE: Yes, sure. The models actually calculated both things. I'm sorry, am I interrupting you? Were you still speaking?

MR. HUNTOON: No, that was the question. Sorry.

MR. TURNURE: Okay. The model is calculating both things. The model is both calculating the incremental capital, as opposed to past capital, but the going-forward capital--the fixed O&M, the variable O&M, and the fuel costs--for all the plants in the region.

At the same time, it is calculating a marginal clearing price for ten demand segments. So from low demand to high demand, period, it's calculating an energy price that is a marginal energy price.

So the highest priced plant in that particular demand segment is setting the marginal clearing price, but each plant has its own production costs calculated separately, and those are added up as another type of output.

MR. HUNTOON: Okay. So you don't--so the production cost does not become based on essentially what you might call a "pool marginal clearing price" for all production? That's not what happens? Is that right?

MR. TURNURE: Yes, that's right. The production costs for each plant are actually tracked separately, and what you can do from that, if you've got the time and the money, is calculate the productivity, the marginal return on each of those plants.

You may have a very cheap plant that's operating in a very high-priced demand segment, for instance.

MR. HUNTOON: Right. I guess one way of looking at it is to say, for example, in the PJM -- in PJM for example, after unbundling of generation has occurred in large part of course by spinoff to affiliates, but nonetheless it is unbundled, generation is getting the locational marginal price so to speak. And as retail rates tend to track that over time as it's sort of phased in, the traditional cost-of-service regulated basis or way in which production would get compensated is becoming obsolete.

And what I'm hearing you say is that that is not something that is being--that is not the way in which your model is approaching this? Is that right? I'm just trying to understand. I'm not trying to argue one way or the other.

MR. TURNURE: Oh, no. We're just calculating wholesale prices and not retail prices. I mean, if there is a transition in some area between a production cost retail price and a wholesale spot price, both of those information sources are available as output. And if people asked us to do that, we could do it whichever way they preferred. But we're not calculating retail price in this exercise.

MR. MARCUS: This is Dave Marcus, if I can try and clarify it. In the case, let's make up a simple hypothetical case.

You've got a system which in one particular load interval has wholesale generators running whose highest cost, one, is 8 a kilowatt hour. Your model will output 8 as the marginal price for that, what you're calling demand interval?

MR. TURNURE: Right. That's right.

MR. MARCUS: The average of the whole set of plants, each of which is less than or equal to 8 in marginal running cost, might be 6 . And under traditional cost-of-service ratemaking, the 6 is the number that would show up in rates?

MR. TURNURE: Yes. And you've got both types of information produced by the model.

MR. MARCUS: And the numbers that are being reported as the gains from going to an RTO, are those the gains in production cost? Or are those the gains in--are those changes in revenue where revenue is calculated as sales or load times marginal price?

MR. TURNURE: They're the production cost numbers in the main summary tables. We are also providing the energy price information, but without further assumptions about the price pass-throughs we weren't doing that particular calculation.

You could take those calculations fairly easily.

MR. MARCUS: So it is perfectly possible to have a situation where the average cost, which is what the production cost is when sunked, is going down while the marginal cost is going up.

MR. TURNURE: Yes. It's a perfectly plausible outcome, that's right. Although if the production cost decreases are big enough, you would expect that sooner or later you would end up with price declines in most places. But that is part of the story of the report, really, is that it's not a uniform story when it comes to the energy prices, even if the production costs are all moving in a downward direction.

MR. MARCUS: Well you've got a clear story about geographical dispersion, but I'm saying for a particular geographic area it is also possible that you could have a lower average cost while the average of the hourly marginal costs went up.

MR. TURNURE: Yes. That's correct.

MR. MARCUS: And if customers were facing marginal price-based retail prices, they would see an increase in their costs. And what you would have is that the transfer to generators would be bigger than the total gain to society. The total gain to society would be parsed to be positive, but the parsing would be a big positive gain to generators, a small loss to customers, and a net gain to society. And your study simply doesn't attempt to parse how the gains are being partitioned between generators and customers.

MR. TURNURE: Yes. That's right.

MR. MARCUS: Okay. Then I think I do understand. Thank you.

MR. WOLVERTON: This is Link Wolverton as a follow up question sort of on one time ago.

How many demand periods a year are you modeling?

MR. TURNURE: We're modeling 10 demand segments and 2 seasons, so 20.

MR. WOLVERTON: Okay.

(Pause.)

MR. RUSSO: This is Tom Russo. Additional questions and comments?

MS. SMITH: This is Denise Smith at Tucson Electric Power. I have I guess an elementary question here on what are you defining as "production cost"? Is it O&M?

MR. TURNURE: Yes. That's broken down in the report in one table, and I'll dig through and tell you which table it is, but just to summarize: it's going-forward capital, which means additional capital for new plants or environmental retrofits or other types of upgrades; and fixed O&M, variable O&M, and fuel.

Let me just find that table for you to sort of give you a sample of the production cost breakdown. Hold on a second.

MR. RUSSO: Denise, while we are waiting, can you tell us your last name?

MS. SMITH: Smith.

MR. RUSSO: Spell it, please?

MS. SMITH: Smith.

MR. RUSSO: Smith? Okay.

(Pause.)

MR. TURNURE: Oh, yes, we don't have the whole production cost breakdown. I was thinking about the distinction made around page 47-48. But just so you know, yes, it would be--I mean the model outputs themselves are capital, fixed O&M, variable O&M, and fuel.

MS. SMITH: And I guess any other savings aren't taken into account in this analysis from anything else?

MR. TURNURE: Well, the simple answer is, no. If you have a specific type of savings that you're interested in, there might be for example administrative and general, you know, that sort of corporate overhead merger type savings. That's not explicitly taken into account here, no.

MS. SMITH: Okay. I was just wondering like the transmission pricing, and the pancaking of the rates, anything--that is not included in here?

MR. TURNURE: Not directly. To the extent that transmission revenue is going to pay for existing, you know, the capital stock, we're not taking that directly into account. It's only reflected in the improvements in economic dispatch and inter-regional trade.

MS. SMITH: Thanks.

(Pause.)

MR. RUSSO: Additional questions?

MR. HOFFMAN: I guess on the hurdle rates--

MR. RUSSO: Who are you, please?

MR. HOFFMAN: This is Biff Hoffman from SRP.

I recognize that the hurdle rates contain two components: (1) transmission costs, and (2) everything else that's a barrier.

Presumably the hurdle rates could, in the calibration case, could never be lower than the transmission rates? Is that correct? And was any effort made to kind of reconcile the hurdle rates with the actual transmission rates and try to figure out whether the implied barriers, what constituted the implied barriers in various cases?

MR. TURNURE: This is Jim Turnure at ICF. I would recommend you would ask that as a follow-up question. What we do have is ICF's normal sort of wholesale set of tariffs or inter-regional, you know, charges that we carry in the model's forecasting.

You could compare those to the hurdle rates that we ended up with after calibration. So that is the sort of thing that, you know, again it gets to a level of detail that I can't just come up with it off the top of my head.

But as an exercise in comparative analysis, it wouldn't be all that difficult to conduct.

MR. HOFFMAN: But you didn't actually do that to see whether the hurdle rates were consistent with reality?

MR. TURNURE: Well I guess I can say that we certainly kept an eye on it as we did the calibration. You know, you're always worried about how the magnitude of these hurdle rates can be reasonable or unreasonable.

But again, this was a team effort and so there were specific people who were doing most of that. And every now and then we would all get together and discuss, you know, how we felt about it.

It would be more explicit and better, really, to go ahead and do a direct, you know, after-the-fact comparison. I mean I would have to say we tried to keep it in mind, and we certainly knew both things as we were proceeding.

MR. RUSSO: This is Tom Russo again. Any other questions, comments?

(No response.)

(Pause.)

MR. RUSSO: Going once. Twice. This is your last chance.

(No response.)

MR. RUSSO: Okay, let's see if we can wrap up.

I want to thank you all very much for participating. I want to apologize for any mishaps with the equipment or in your ability to really follow the discussions.

Just one thing I will point out. Your comments, again, are due April 9th. And if you could be so kind to separate your comments on the study in the report from your request for additional model runs or things that you would like the FERC to conduct, that would really be appreciated.

This transcript here should be available approximately 11 days from now. Some of you may have questions about the March 25th Technical Conference being held in Washington, D.C.

Specifically, it is going to be the same program. There won't be a presentation. We expect Jim Turnure and the Associates from ICF and Staff to be available to answer questions. And that's about it.

Are there any other comments from the participants?

(No response.)

MR. RUSSO: Okay, in that event I want to thank you and bid you a good day.

(Many voices saying 'thank you'.)

MR. RUSSO: Thank you.

(Whereupon, at 3:45 p.m., Tuesday, March 19, 2002, the telephone conference in the above-entitled matter was adjourned.)

1